Comments of the Vote Solar Initiative On Errors in the Draft E3 Net Energy Metering Study

1. Introduction

The Vote Solar Initiative (Vote Solar) appreciates this opportunity to submit comments on apparent errors in the draft cost/benefit analysis of net energy metering (Draft NEM Study) in California, requested by CPUC and performed by the Energy and Environmental Economics (E3) consulting firm and released on September 26, 2013. Vote Solar submits these comments in accordance with the e-mail of September 26, 2013 from Ehren Seybert of the CPUC Energy Division. Vote Solar appreciates the significant effort that E3 and Energy Division have put into the Draft NEM Study, and provides these comments in an effort to correct certain mistakes in the draft and to contribute to a more accurate final NEM Study.

Vote Solar has identified a considerable list of concerns with the Draft NEM Study's scope, methodology, inputs and calculations. In an effort to keep these comments within the 5-page limit requested by Energy Division, Vote Solar addresses in full only a subset of these concerns. In addition, we fully concur with the additional and distinct concerns raised by The Alliance for Solar Choice (TASC) in the comments on the Draft NEM Study which they submitted to Energy Division today, including the following:

- The scope of the analysis should be limited to exports-only.
- Results are highly suspect due to reliance on outdated rates and anticipated rate reform.
- NEM generation should be valued at 100% of the renewable premium.
- The study fails to show participant impacts as required by AB 2514, is inconsistent with the Commission's Standard Practice Manual, and should include societal costs and benefits.
- The study should not use a Resource Balance Year (RBY) in the Base Case.
- The study should use existing methods to allocate generation and distribution capacity costs.
- CARE customers should be excluded from the household income analysis.
- Residential minimum bill impacts should be included.
- The return of GHG allowance revenues should be recognized.

2. Errors in the Draft NEM Study

a. Comparison of 2010 and 2013 Results / Use of Lifecycle Costs

The draft report's de-emphasis of the 20-year lifecycle results is incorrect and misleading, given that renewable DG is a long-term resource. Reporting the value of all net metered DG on the basis of a future year "snapshot" in 2020 does not fully capture solar's value as a hedge against future increases in fossil fuel prices and the costs to mitigate GHG emissions.

The Executive Summary does not present results for the 20-year lifecycle analysis. This is misleading when compared to the Executive Summary of the 2010 report, which only reported 20-year lifecycle results. E3 should highlight annual NEM impacts based on the 20-year analysis, not for the 2020 "snapshot," so that the results of the 2010 and 2013 NEM reports can be directly compared on an apples-to-apples basis. The new study's results for the 20-year lifecycle analysis are buried in Table 40, and show smaller impacts than the 2010 study at full CSI build-out. Only on page 78 does E3 note that the full CSI impacts are smaller in this study than in the 2010 work.

On a 20-year lifecycle basis, NEM impacts at the full 5% NEM cap are $236 million per year, much lower than the 2020 snapshot of $359 million, and just 0.68% of the revenue requirement, not 1.03%.

b. Need to Report Results by Rate Schedule in the Body of the Study

The Draft NEM Study does not report results by rate schedule. Doing so is particularly important since the Commission is considering significant changes to residential rates in R.12-06-013. Stakeholders in that proceeding have proposed changes to residential rates including moving residential customers gradually to default time-of-use rates. It would be very useful for policymakers and stakeholders to see how NEM impacts vary by rate schedule. E3 provides results by rate schedule in the NEM Summary Tool workpapers in the form of detailed results for over 9,000 "bins," but those results must be aggregated by rate schedule and included in the study itself as many readers will not be able to extract them from the workpapers. Furthermore, the draft report does not comment on how the results were impacted by the reductions in upper tier rates from the 2008 rates used in the 2010 study to the 2011 rates used in the new work.

c. Failure to Include Avoided High-Voltage Transmission Costs

The Joint Solar Parties commented last fall that the E3 avoided cost model fails to include avoided CAISO-jurisdictional high-voltage transmission costs for Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), even though these investor-owned utilities (IOUs) have calculated these marginal costs, and E3 included all other IOU marginal T&D costs for sub-transmission and distribution. Pacific Gas & Electric's (PG&E) marginal transmission costs include CAISO-level costs. E3's response in the December 2012 Final SOW was that the avoided costs used in the NEM Study would include "[c]onsideration of FERC-jurisdictional transmission costs at the CAISO." E3's Snu Price acknowledged at the September 27 workshop that these avoided transmission costs still are not included in the E3 avoided cost calculator, and page C-44 states that "[t]ransmission avoided costs are for subtransmission or area transmission assets "downstream" of the CAISO." In contrast, Vote Solar notes that the recent draft San Diego Solar DG study included such avoided CAISO-level transmission costs for SDG&E.[1]

Behind-the-meter DG clearly provides significant output in peak periods, when the transmission system peaks, serving both on-site loads (where the power never touches the grid) and for export to the distribution system (where the power serves nearby distribution loads without using the transmission system). Past impact evaluation reports for the CSI have shown that CSI systems reduce peak transmission system loadings on at least a one-for-one basis, make additional capacity available on the transmission system, and thus avoid transmission expansion costs.[2] A major policy reason for the state's <u>distributed</u> generation programs is to avoid the need for more bulk transmission lines.[3]

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[1] San Diego Distributed Solar PV Impact Study, at 48-49, Tables 19-20.

[2] Itron, *2009 CSI Impact Evaluation Report*, at page ES-17. Also, Itron, "CPUC Self-Generation Incentive Program – Sixth Year Impact Evaluation Report" (August 30, 2007), at 5-29 to 5-33. These Itron reports are available on the CPUC website at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm and http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

[3] For example, the California Energy Commission's *2009 Integrated Energy Policy Report (IEPR)*, at pages 8 and 95) recognized the importance of DG as an alternative to investments in T&D infrastructure, stating "*[b]ecause the generation is located near the location where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times.*"

SCE's most recent GRC (A. 11-06-007) shows a marginal cost for CAISO-controlled transmission of $59.18 per kW-year (2012 $).[4] The draft San Diego Solar DG study used a marginal cost of CAISO transmission for SDG&E of $102.83 per kW-year, escalating at 3% per year.[5] Because demand on the CAISO grid peaks coincident with system demand, these avoided CAISO transmission costs should be allocated in the same manner as generation capacity costs, as was done in the draft San Diego Solar DG study.

d. Failure to Use Updated GRC Marginal Costs, and Inconsistency between Avoided Cost and Cost-of-Service Models

E3 stated in the Final SOW that its study would use "the most recently available marginal cost estimates." This was in response to a comment from the Joint Solar Parties that the SCE and SDG&E avoided T&D values in the E3 model were not based on their latest general rate case filings (A. 11-06-007 and A. 11-10-002). E3 should update these costs to SCE's and SDG&E's most recently-filed 2011 marginal T&D costs, as summarized in the table below. The values in parentheses show the values apparently used in the E3 avoided cost calculator. PG&E's avoided distribution costs are based on their 2011 general rate case values.

Table 1: *SCE and SDG&E Marginal T&D Costs (2012 $/kW-year) from Current GRCs*

Marginal T&D Cost Category	**SCE**	**SDG&E**
Distribution	91.37 *(30.10)*	74.06 *(52.24)*
Substation		27.85 *(21.08)*
Sub-transmission	35.06 *(23.39)*	
Sources:	*A.11-06-007, Exhibit SCE-2, at 30 (Table I-13) and SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.*	*A. 11-10-002, Chapter 6, Tables RME-01 and RME-02.*

More generally, the avoided cost model uses E3's own evaluation of SCE's and SDG&E's marginal distribution costs, rather than using these utilities' marginal distribution costs from their most recent GRCs, shown in the table above. It is also not clear whether E3's Cost-of-Service analysis used SCE's and SDG&E's most recent GRC marginal costs, or some other utility estimates provided in data responses to E3 and which have never been publicly vetted. Only the PG&E marginal distribution costs from its GRC appear to have been used consistently in both portions of the E3 study. However, even for PG&E, the avoided cost model uses PG&E's marginal transmission costs from its GRC, while the Cost-of-Service model uses its filed average transmission rate (based on the recommendation of "a PG&E rates expert" – page D-16). **The E3 study would be greatly improved through the use of a single set of marginal T&D costs from the most recent IOU GRCs, used consistently in both the avoided cost model and the Cost-of-Service study.** The confusion of the reader is only magnified by footnote 35 in Appendix C, which states that "T&D avoided costs provided for the NEM report are not included in the updated avoided cost spreadsheet tool," which suggests that the avoided cost model provided to the parties does not include the actual avoided T&D values that E3 used.

[4] A.11-06-007, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.
[5] San Diego Distributed Solar PV Impact Study, at 48, Table 19.

e. Spreadsheet Error in the Allocation of Capacity Costs

E3 made a spreadsheet error that shifts its generation capacity values one hour later into the afternoon. This has a significant impact in reducing solar's capacity value. We do not know whether the same error exists for the allocation of T&D capacity costs, as those are hard-wired numbers.

Column "AK" of the "Hourly Allocation" tab in the avoided cost model makes use of Excel's "Offset" function to gather the hourly capacity allocators from the "Capacity Allocation" tab of the model. However, the row offset variable in the function needs to be rounded to the nearest integer (i.e. hour) so that Excel does not look up the value for the preceding hour (for example, Excel will look up hour 1 when the variable equals 1.999999…). The problem can be fixed by changing the formula to ensure the correct hour is referenced, by rounding the "24 x (current datetime – start datetime)" term to the nearest integer. Thus, for example, the formula in Cell AK7 could be changed as indicated below:

```
OFFSET('Capacity Allocation'!$D$2,ROUND((C27- $C$27)*24,1),MATCH(StartYear,'Capacity Allocation'!$D$1:$AU$1,0)-1)
```

This one-hour shift in the capacity allocation appears to be a significant error, and it incorrectly reduces the capacity value of solar PV. For example, in 2012 the model notes that the 2012 marginal solar ELCC is 49% (i.e. see cell G20 of the "Avoided RPS: tab.). We observe that fixing the lag problem identified above indeed results in a 2012 capacity-allocation-weighted average solar output equal to 49% (i.e. sumproduct of columns AH and AK in the hourly tab). Without the correction, however, the value is 35%. Thus, the model is incorrectly de-rating the ELCC for solar PV by almost 30% (0.35/0.49), due to this spreadsheet error.

For 2020 the results are even more extreme: the RPS tab indicates a 32% ELCC; however, the sumproduct of the solar output (column AH) and the allocators (column AK) is 18%. Thus, the advertised ELCC is 78% above the value actually used. The four figures in Figure A1 of the attached Appendix A provide two examples illustrating the problem with the incorrectly lagged allocation factors: solar PV output is less correlated with the most important "capacity allocation" hours if that allocation is incorrectly lagged one hour later in the day.

f. High Case Avoided Capacity Costs in Figure 15

Figure 15 on page 62 showing the Base, High, and Low sensitivity scenarios appears to show that the High Case (with a 2007 resource balance year and 2013 ELCCs) has a lower avoided capacity costs (the dark red stripe) than the other two cases. This does not make sense, as the changes made in the High Case should increase avoided capacity costs. We have not had the time needed to determine the source of this apparent error.

g. Vintaging of ELCCs Should Be Clarified and Included in the Base Case

Vote Solar was unable to find a means to vintage the ELCCs used in the avoided cost model, as E3 states that it did for the High Case (Table 8). It is unclear if E3 assigned the 2013 ELCC to all NEM systems in the High Case, or assigned to each NEM system the ELCC for the year in which it was installed. This point should be clarified.

ELCCs should be vintaged in the Base Case, not just in the High Case, because many NEM systems were installed long before the state committed to major RPS solar capacity. This issue was not discussed in the scoping comments, as the details of E3's new allocation of generation capacity costs was not known. A NEM system should receive the ELCC of the year in which it enters service (or of the first year of the analysis if it was installed many years earlier). Otherwise, the capacity value of short-lead-time DG resources is reduced by central station capacity that may (or may not) come on-line years later.

h. Removal of SONGS from the Resource Balance Year (RBY) Calculation

SCE announced in June that the SONGS nuclear units will close permanently. Based on Table 7 in Appendix C, removing the SONGS capacity will advance the RBY from 2017 to 2016. Although Vote Solar does not agree with the RBY concept, if it is used the RBY should be 2016.

i. Market Heat Rates Should Use Post-SONGS Values

The draft report notes (at Table 20, page 55) that forward market heat rate projections were taken from the 2010 CPUC Long Term Procurement Plan. The model shows a 8,377 Btu/kWh market heat rate in 2012 but, for 2013 to 2020, it interpolates between an average 2007-2012 heat rate (7,739 Btu/kWh) to a 2020 heat rate equal to 7,438 Btu/kWh, which is then held constant. Given that SONGS is now permanently out of service, and that the 2007-2012 heat rate includes SONGS in every year except 2012, it is incorrect to show heat rates dropping sharply from 2012 to 2013. Actual market heat rates in 2013 to date have averaged about 8,200 Btu per kWh (with GHG costs removed), so the sharp drop in heat rates which E3 assumed in 2013 in Figure 13 of Appendix C has not occurred. It would be more reasonable to simply extend the 2012 market heat rate into the future with a slow decline as more efficient gas-fired resources are added.

At page C-22, E3 states that "while the composition of the generation fleet may change due to increased renewable energy injected into the grid, we do not expect the heat rates of the dispatch units on the margin to change substantially. Accordingly, the rate of increase after 2013 is driven almost exclusively by the forecast change in natural gas prices (see Figure 10)." We agree, but think that the correct number for avoided energy costs should reflect post-SONGS-closure market heat rates. In saying that market heat rates will not "change substantially," E3 appears to be referring to 2020 vs. the 2007-2012 average (i.e. 7,438 vs.7,739 Btu/kWh, respectively). However, this ignores that market heat rates increased sharply from 2011 to 2012 due to SONGS being offline (as shown by the spike in market heat rates in 2012 that is in E3's Figure 13). The increase in market heat rates resulting from the loss of SONGS is a substantial change, and that increase has persisted through 2013 to date. Figure A2 in Appendix A of these comments illustrates the numbers, with the red line indicating Vote Solar's proposed revision to the market heat rates.

Vote Solar appreciates the opportunity to present these comments on the errors that we have identified in the Draft NEM Study. We look forward to reviewing a Final Study which addresses these concerns.

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Appendix A: Vote Solar Comments on Errors in E3 Net Energy Metering Study

Figure A1: Spreadsheet Error Shifting Capacity Values to One Hour Later

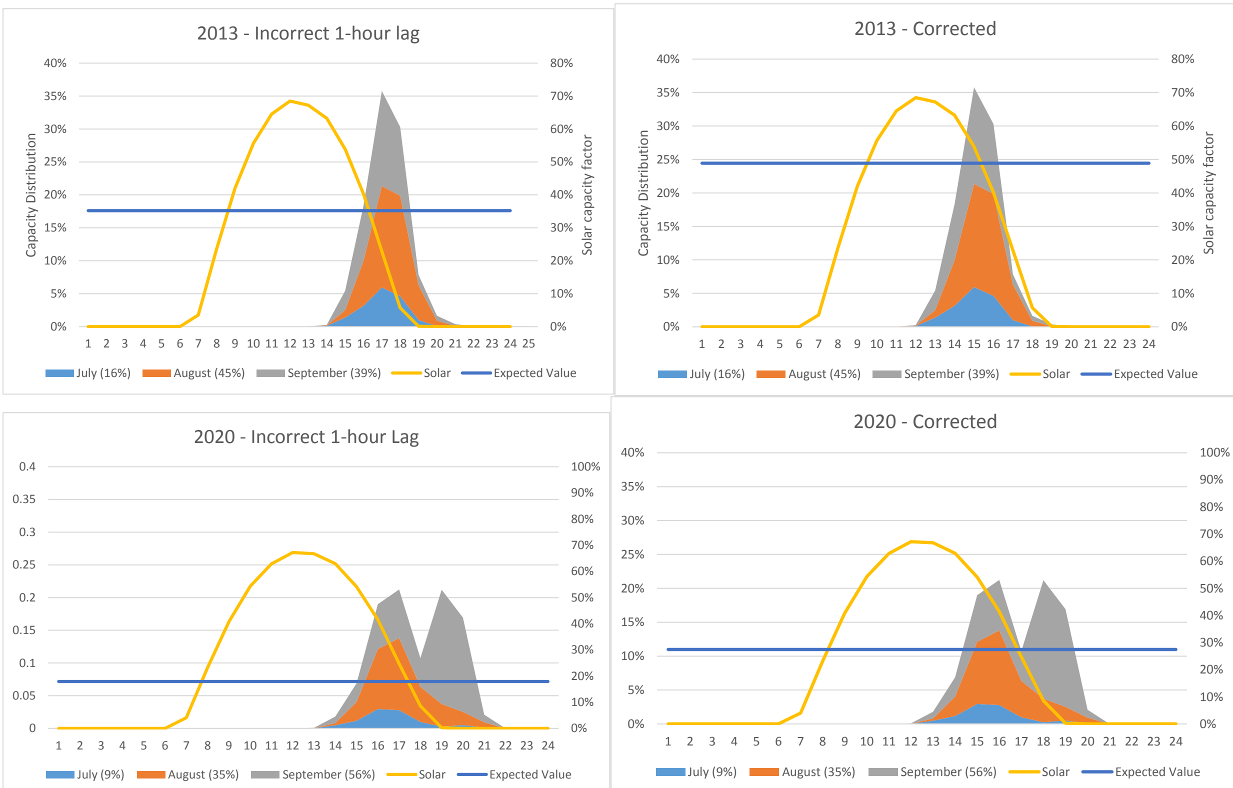

Figure A2: Revise Market Heat Rate to Reflect Post-SONGS Values